TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

New Hope Power Company
8001 U.S. Highway 27 South
South Bay, Florida 33493

Okeelanta Cogeneration Plant
New Emission Unit 006
Project: Construction of New Natural Gas Fired Boiler (Cogeneration Boiler D)
Palm Beach County

PROJECT

ARMS Facility ID No. 0990332
Project No. 0990332-021-AC (PSD-FL-196R)

COUNTY

Palm Beach, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
Permitting Section
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

June 24, 2013

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

New Hope Power Company (NHPC) operates a 140 megawatt-net (MW-net) Okeelanta Cogeneration Plant consisting of three biomass-fired steam boilers. The plant is located adjacent to the Okeelanta Corporation sugar mill and refinery, approximately 6 miles south of the city of South Bay on U.S. Highway 27 South in western Palm Beach County. The plant has three essentially identical cogeneration boilers (Cogeneration Boilers A, B and C) that primarily combust biomass consisting of bagasse and wood to generate steam and electricity. Natural gas is used as a supplemental fuel in the boilers.

The Okeelanta Cogeneration Plant generates steam to produce electrical energy year-round, but also supplies the adjacent Okeelanta sugar mill with process steam during the sugar cane grinding season, approximately October through March of each year. The plant also supplies the Okeelanta sugar refinery with process steam year-round. The Okeelanta Cogeneration Plant is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The UTM coordinates of the plant are Zone 17, 524.9 kilometers (km) East and 2940.1 km North. Figure 1 below shows the location of Palm Beach County, while Figure 2 is an aerial view of the New Hope Power Company Okeelanta Cogeneration Plant and the adjacent sugar mill.

Figure 1. Location of Palm Beach County.

Figure 2. Aerial View of the NHPC Facility.

1.2. Project Description

1.2.1. Overview

NHPC is requesting authorization to add a natural gas-fired boiler (Cogeneration Boiler D) to the Okeelanta Cogeneration Plant. The addition of a natural gas-fired boiler will allow NHPC the flexibility to produce steam and electricity year-round based on the most economical fuel or fuel mix. Steam produced by the new boiler will be tied into the existing steam system, which serves two steam turbine electrical generators (STEG) and provides the Okeelanta sugar mill and refinery with steam. The current maximum electrical generating capacity of the Okeelanta Cogeneration Plant of 140 megawatts, net (MW-net) will not be increased with the addition of the new boiler.

The proposed location for the new natural gas-fired Cogeneration Boiler D at the Okeelanta site is shown in Figure 3 and Figure 4. Approximately one acre of the existing Okeelanta site will be used for the Cogeneration

Boiler D power block. A flow diagram of the proposed configuration with Cogeneration Boiler D is shown in Figure 5.

Figure 3. Aerial View Boiler D Location at the Site.

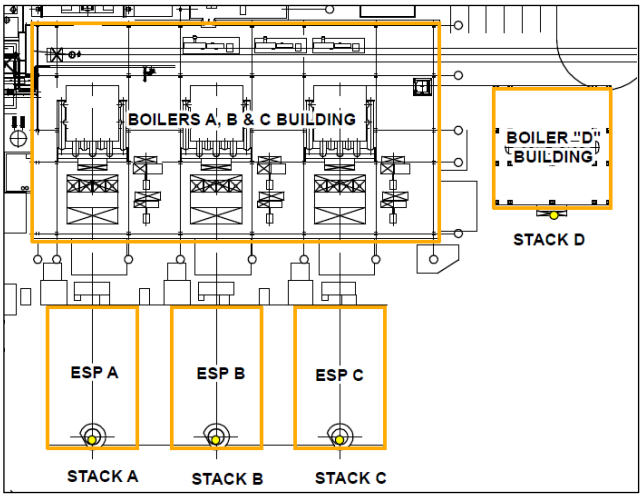

Figure 4. Schematic View of Boiler D at the Site.

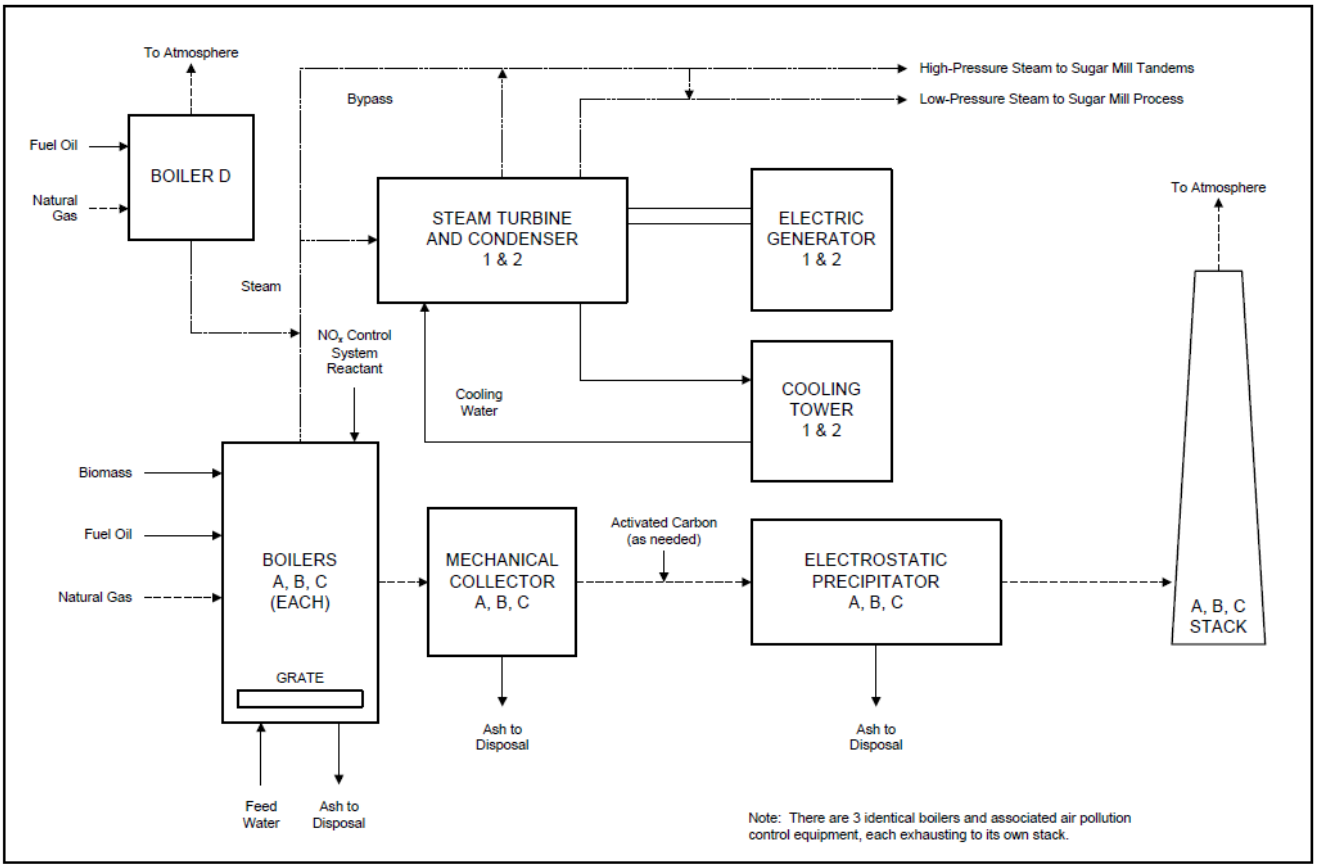

Figure 5. Flow Diagram with Boiler D Integrated with other Cogeneration Boilers at the Okeelanta Site.

The NHPC requested that Cogeneration Boiler D be permitted for 8,760 hours per year (hr/yr) of operation. According to the NHPC, Cogeneration Boiler D will be a modern design natural gas-fired boiler. The minimum expected combustion efficiency while burning pipeline quality natural gas is expected to be 85 percent (%). No. 2 (distillate) fuel oil will be used as an emergency fuel during times of natural gas curtailment. When natural

gas is available, the use of No. 2 fuel oil will be limited to 48 hours in any consecutive 12 month period. The distillate fuel oil will contain a maximum sulfur content of 0.05% by weight while the natural gas will have no more than 2 grains of sulfur per 100 standard cubic feet (2 gr/100 scf).

The 48 hours limitation on fuel oil use in Boiler D is so that the boiler will be categorized as a Gas 1 subcategory unit per Tile 40 Code of Federal regulations (CFR) Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process. A unit in the Gas 1 subcategory has no emissions limits in Subpart DDDDD. Instead only work practice standards are required. If a unit burns more than 48 hours of liquid fuel in a calendar year, then the unit is classified as a Liquid Fuel subcategory unit and is subject to emission limits for carbon monoxide (CO), mercury (Hg), hydrogen chloride (HCl) and filterable particulate matter (PM) or total select metals (TSM). It should be noted that NHPC has asked the EPA to reconsider the applicability of Subpart DDDDD to the NHPC boilers. If the requirements of NESHAP Subpart DDDDD are changed with regard to the applicability, the air construction permit will be modified accordingly.

The proposed maximum 1-hour average heat input to the boiler is 589 million British thermal units per hour (MMBtu/hr) which corresponds to a maximum 1-hour average steam production rate of 440,000 pounds per hour (lb/hr). The proposed maximum 24-hour average heat input is 536 MMBtu/hr which corresponds to a maximum 24-hour average steam production rate of 400,000 lb/hr.

1.2.2. Air Emissions and Proposed Pollution Control Equipment

The project results in emission increases of nitrogen oxides (NO_X), CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), PM, PM with a mean diameter of 10 microns or less (PM_{10}), PM with a mean diameter of 2.5 microns or less ($PM_{2.5}$), sulfuric acid mist (H_2SO_4 also called SAM), lead (Pb), Hg, fluorides (F) and carbon dioxide equivalents (CO_2e) for greenhouse gases (GHG). NHPC proposes the following air pollution controls on Cogeneration Boiler D:

- Ultra-low NO_X burners (ULNB) and over-fired air (OFA) to control NO_X emissions;
- Good combustion practices (GCP) and clean fuels to minimize formation of CO and VOC; and
- Use of low-sulfur, pipeline-quality natural gas (primary fuel) and low sulfur fuel oil (emergency fuel) for control of particulate matter $PM/PM_{10}/PM_{2.5}$, SO_2 and H_2SO_4.

This project will add Emission Unit (EU) 006 (highlighted in turquoise) to the existing emission units at the NHPC Okeelanta Cogeneration Plant (see Table 1**Error! Reference source not found.** below).

TABLE 1 – EMISSION UNITS AT NHPC OKEELANTA COGENERATION PLANT (ID NO. 0990332).

EU ID No.	Emissions Unit Description
001	Cogeneration Boiler A
002	Cogeneration Boiler B
003	Cogeneration Boiler C
004	Cogeneration Plant - Material Handling and Storage
005	Cogeneration Plant – Miscellaneous Support Equipment
006	Cogeneration Boiler D

2. AIR POLLUTION REGULATIONS

2.1. State Rules

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish air quality regulations as part of the Florida Administrative Code (F.A.C.), which includes the applicable chapters contained in Table 2:

TABLE 2 – APPLICABLE RULES FROM THE F.A.C.

Chapter	Description
62-4	Permits
62-17	Electrical Power Plant Siting
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

2.2. Federal Rules

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60) that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR 52, Subpart K – Florida; also known as the State Implementation Plan (SIP) for Florida.

2.3. Overview of Key Regulations Applicable to the NHPC Natural Gas Boiler Project

- The facility is a major source of hazardous air pollutants (HAP).
- The facility does not include units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons/year. Key regulated pollutants include CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC and SAM.
- The facility's boilers are not subject to Clean Air Interstate Rule (CAIR) because they meet the exemption in CAIR for cogeneration units that generate less than 219,000 megawatt-hours (MW-hr) of electricity in any calendar year.
- The facility is a major stationary source in accordance with Department Rule 62-212.400, F.A.C. – Prevention of Significant Deterioration (PSD).
- This project (as discussed below) **does** trigger a PSD review and a requirement to conduct a Best Available Control Technology (BACT) pursuant to Department Rule 62-212.400, F.A.C.
- The proposed project includes units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations Part 60 (40 CFR 60).
- The proposed project includes units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

- The project is subject to certification under the Florida Power Plant Siting Act, 403.501-518, F.S. and Chapter 62-17, F.A.C.

2.4. New Source Performance Standards (NSPS) Applicable to the Project

2.4.1. 40 CFR 60, Subpart A – General Provisions

Link to NSPS Subpart A

Several sections from NSPS Subpart A apply to this project.

2.4.2. 40 CFR 60, Subpart Da - Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

Link to NSPS Subpart Da

This NSPS applies to all units capable of combusting more than 73 MW or 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel) for which construction commenced after September 18, 1978. Subpart Da limits emissions of NO_X, SO_2 and PM from fossil fuel and wood firing. EPA issued changes to this NSPS on February 27, 2006 (71 Federal Register (FR) 9866) and February 16, 2012 (77 FR 9450). The revisions are applicable to new affected facilities that commence construction after February 28, 2005 and after May 3, 2011, respectively. For new units burning gaseous and/or liquid fuels, for which construction commences after May 3, 2011, the following limits apply:

- PM – Units that burn only gaseous or liquid fuels with potential SO_2 emission rates of 0.060 lb/MMBtu or less, and do not use a post-combustion technology to reduce SO_2 or PM emissions, are exempt from the PM emission limit;
- SO_2 – emissions are limited to 1.0 pound per megawatt hour (lb/MW-hr) gross energy output, or 1.2 lb/MW-hr net energy output, or 97% reduction, based on a 30-day rolling average;
- NO_X – emissions limited to 0.70 lb/MW-hr gross energy output, or 0.76 lb/MW-hr net energy output, based on a 30-day rolling average;
- Visible emissions (Opacity) – limited to 20% opacity (6-minute average) except up to 27% opacity is allowed for one 6-minute period per hour; and
- NO_X + CO – as an alternative to meeting the NO_X standard above, the owner/operator may elect to meet a combined limit for NO_X plus CO emissions of 1.1 lb/MW-hr gross energy output, or 1.2 lb/MW-hr net energy output, based on a 30-day rolling average.

For facilities which commence construction, reconstruction, or modification after May 3, 2011, the above emission limits apply at all times, including during periods of startup, shutdown, and malfunction. Subpart Da requires continuous emission monitoring systems (CEMS) in order to demonstrate compliance with the emission limits. Units that burn only gaseous or liquid fuels with potential SO_2 emission rates of 0.060 lb/MMBtu or less, and that do not use a post-combustion technology to reduce SO_2 or PM emissions, are not required to install a COMS, but instead can elect to monitor opacity using EPA Test Method 9 or submit a site-specific monitoring plan. Also, such units are not required to install a CEMS for SO_2. A CEMS for NO_X is required, and if the unit elects to comply with the NO_X + CO combined emission limit, a CO CEMS is required.

For units demonstrating compliance with the output-based standards, a continuous volumetric flow rate monitor measuring the flow rate of the exhaust gases is required. In addition, a wattmeter and process steam continuous monitors are required to measure gross electrical output as well as gross process steam output.

2.4.3. 40 CFR 60, Subpart TTTT - Greenhouse Gas Emission for New Stationary Sources: Electric Utility Generating Units

Link to Proposed NSPS Subpart TTTT

On April 13, 2012, EPA proposed a NSPS for GHG emissions for electric utility generating units (EGU), i.e., 40 CFR 60 Subpart TTTT (77 FR 22392). This proposed NSPS is potentially applicable to the new natural gas Cogeneration Boiler D at the NHPC site. Units that are subject to this NSPS are ones that that commenced construction after April 13, 2012, and which have a base load rating of more than 73 MW or 250 MMBtu/hr heat input of fossil fuel. The proposed CO_2 emission limit under Subpart TTTT is 1,000 lb/MW-hr on a 12-operating month annual average basis. EPA has not yet finalized this proposed rule.

2.5. National Emission Standards for Hazardous Air Pollutants (NESHAP) Applicable to the Project

2.5.1. 40 CFR 63, Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters

Link to NESHAP Subpart DDDDD

EPA issued the final version of NESHAP Subpart DDDDD on January 31, 2013 (78 FR 7138). This NESHAP applies to all Industrial, Commercial, and Institutional Boilers and Process Heaters at major sources of HAP emissions. A major source of HAP emits 25 tons per year (TPY) or greater of all HAP or 10 TPY or greater of a single HAP. So long as the natural gas fired Cogeneration Boiler D at the NHPC site is classified as Gas 1 subcategory unit only work practice standards apply to the boiler. Per §63.7575:

"*a unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.*"

Instead of emission limits, a Gas 1 subcategory unit with a heat input of 10 MMBtu/hr or greater must:

"*Conduct a tune-up of the boiler or process heater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart.*"

If Boiler D does not fall into the Gas 1 subcategory, i.e., it burns a liquid fuel for more than 48 hours during any calendar year during periods when there is no gas curtailment, Subpart DDDDD has emission limits that apply to the boiler. If Cogeneration Boiler D falls into the subcategory of units that are designed to burn Light Liquid Fuel (No. 2 fuel oil) then the following emission limits apply:

- HCl – emissions are limited to 4.4×10^{-04} lb/MMBtu of heat input, 4.8×10^{-04} lb/MMBtu of steam output or 6.1×10^{-03} lb/MWh;
- Hg – emissions are limited 4.8×10^{-07} lb/MMBtu of heat input, 5.3×10^{-07} lb/MMBtu of steam output or 6.7×10^{-06} lb/MWh;
- CO – emissions are limited to 130 parts per million by volume on a dry basis (ppmvd) corrected to 3% O_2, 3-run average , 0.13 lb/MMBtu of steam output or 1.4 lb/MWh; 3-run average; and
- Filterable PM or TSM – emissions are limited to 1.3×10^{-02} lb MMBtu of heat input (7.5×10^{-05} lb/MMBtu of heat input TSM) or 1.5×10^{-02} lb/MMBtu of steam output or 1.8×10^{-01} lb/MWh; or (8.2×10^{-05} lb/MMBtu of steam output or 1.1×10^{-03} lb/MWh TSM).

The compliance methods for the above listed emission limits are provided in Table 5 of NESHAP Subpart DDDDD.

3. PSD APPLICABILITY

3.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal ambient air quality standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants.

Commonly addressed PSD pollutants in the power industry include: CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, SAM, Pb, F, and Hg.

Additional PSD pollutants that are more common to certain other industries include: hydrogen sulfide (H_2S), total reduced sulfur (TRS) including H_2S, reduced sulfur compounds (RSC) including H_2S, municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (dioxin/furan), MWC metals measured as PM; MWC acid gases measured as SO_2 and HCl, and municipal solid waste (MSW) landfill emissions as non-methane organic compounds (NMOC).

As defined in Rule 62-210.200(Definitions), F.A.C., a stationary source is a "major stationary source" (major PSD source) if it emits or has the potential to emit (PTE):

- 250 tons per year (tons/year) or more of any PSD pollutant; <u>or</u>
- 100 tons/year or more of any PSD pollutant <u>and</u> the facility belongs to one of the 28 listed PSD major facility categories.

The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input". The given category applies to the NHPC facility before and after the proposed project. The NHPC facility is a major stationary source based on actual emissions of and potential to emit 100 tons/year or more of several individual PSD pollutants.

For major stationary sources such as the NHPC facility, PSD applicability for projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200(Definitions), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200(Definitions), F.A.C. of a PSD pollutant from the project that equals or exceeds the respective SER is considered "significant". SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average.

Although a facility may be "major" (i.e. emits or has the potential to emit 100 or 250 TPY as applicable) for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding significant emission rates given in Table 3.

According to 40 CFR 52.21, six greenhouse gases (GHG), are also be subject to regulation at new stationary sources that will emit or have the potential to emit 100,000 tons/year (SER equal to 75,000 tons/year) expressed as the carbon dioxide equivalent emissions (CO_2e). This requirement has not been incorporated into Department rules but is a separate requirement of the EPA.

TABLE 3 – LIST OF SER BY PSD-POLLUTANT. [1]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
$PM/PM_{10}/PM_{2.5}$	25/15/10	Ozone (VOC) [2]	40
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
Ozone (NO_X) [2]	40	SAM	7
SO_2	40	Pb	0.6

Pollutant	SER (TPY)	Pollutant	SER (TPY)
Hg	0.1	GHG (CO_2e)	75,000 [3]

1. Excluding fluoride and those pollutants defined for Pulp and Paper, MWC, MSW landfills.
2. Ozone (O_3) is regulated by its precursors (VOC and NO_X). PSD for $PM_{2.5}$ can be triggered by its precursors (NO_X and SO_2).
3. GHG is subject to federal regulation for projects at this stationary source that will result in an emissions increase 75,000 TPY of GHG (as CO2e) or more. GHG regulations have not been incorporated into Department rules.

The project is located in Palm Beach County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The NHPC natural gas boiler project will emit the following PSD-pollutants SO_2, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SAM, VOC, CO_2e, and small amounts of mercury and lead.

3.2. PSD Applicability for Proposed NHPC Boiler Project

The applicant submitted a PSD applicability analysis which is shown in Table 4 below. As seen from the table, according to the applicant emissions of NO_X, CO, PM_{10}, $PM_{2.5}$ and GHG will exceed the PSD SER. Accordingly BACT determinations will be required for these pollutants. With regard to GHG, the applicant must obtain a PSD GHG permit and associated BACT determination from EPA Region 4. EPA is currently processing the GHG permit application.

TABLE 4 – APPLICANT'S PSD APPLICABILITY ANALYSIS (TPY).

Pollutant	Boiler D [1]	Contemporaneous Emission [2]	Total [3]	PSD SER	Trigger PSD?
SO_2	19.54	<<0.1	19.54	40	No
NO_X	140.74	6.56	147.30	40	**Yes**
CO	187.65	43.98	231.63	100	**Yes**
PM (f + c) [1]	17.48	<<0.1	188.3	25	No
PM_{10} (f + c) [2]	17.48	0.51	17.99	15	**Yes**
$PM_{2.5}$ (f + c) [2]	17.48	2.99	20.47	10	**Yes**
SAM	0.06	<<0.1	0.06	7	No
VOC	12.65	<<0.1	12.65	40	No
Lead	0.18	<<0.1	0.18	0.6	No
GHG (CO_2e)	274,446	62,587	337,033	75,000	**Yes**
HAP	4.35 [4]	N/A	4.35	N/A	N/A
Mercury	6.5 lb/yr	<<0.1	6.5 lb/yr	200 lb/yr	No

1. Emission numbers based on 100% natural gas usage in boiler. Oil firing limited to 48 hours in any calendar year.
2. Contemporaneous emissions increases and decreases at the facility for all projects that occurred over the previous five-year period for the pollutants that triggered PSD netting analysis. Specifically the Cogeneration Boiler A Natural Gas Conversion project authorized by Permit No. 0990332-019-AC (June 6, 2012)
3. Total increase in TPY from natural gas fired Boiler D project and all contemporaneous emission increases/decreases.
4. Of the 4.35 TPY of HAP, 4.14 TPY is hexane (C_6H_{14}).

4. DEPARTMENT'S BACT REVIEW

4.1. Definition of BACT

Rule 62-210.200, F.A.C. defines "BACT" as:

An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*

3. The emission limiting standards or BACT determinations of Florida and any other state;

determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA. BACTdeterminations for each applicable pollutant for natural gas fired Cogeneration Boiler D at the NHPC site are provided in the following sections. The general design characteristics of the proposed natural gas boiler are given in **TABLE 5** below.

TABLE 5 – NATURAL GAS BOILER DESIGN CHARACTERISTICS.

Parameter	Description	
Fuel	Natural gas	
Heat Input Rate	1-hour maximum: 589 MMBtu/hr	24-hour maximum: 535.5 MMBtu/hr
Thermal Efficiency	Minimum of 85%	
Steam Production	Max. 1-hr: 440,000 lb/hr steam	Max. 24-hr: 400,000 lb/hr steam
Annual Heat Input Rate	4,691,238 MMBtu/yr	
Stack Parameters	8.2 feet diameter (maximum); 150 feet tall (minimum)	
Flue Gas	314,379 actual cubic feet per minute (acfm) at 350 °F	
Particulate Control	Clean natural gas	
NO_X Control	Ultra-low NO_X burners	
SO_2 Control	Low sulfur, clean natural gas	
VOC and CO Control	Good combustion practices (GCP)	

TABLE 6 below provides limits for all pollutants subject to BACT from the EPA's RACT/BACT/LAER Clearinghouse (RBLC) survey for natural gas fired boilers similar in size and function to the proposed Cogeneration Boiler D. These BACT determinations were issued within the last 11 years, i.e., since 2002. The applicants' proposal for pollutant emission limits is given at the top of the table (highlighted in turquoise).

TABLE 6 – EMISSIONS IN LB/MMBTU – BOILER WITH USES OR CAPACITIES SIMILAR TO PROPOSED NHPC PROJECT.

Project Location	Heat Input [1]	CO [2]	NO_X [3]	$PM/PM_{10}/PM_{2.5}$ [4]
Boiler D	**535.5**	**0.08 (30 day) GCP**	**0.06 (30 day) (ULNB, OFA)**	**NL (FNG, LOU)**
Recent RBLC Survey	N/A	0.024 – 1.0	0.0076 – 0.09	0.0050 – 0.10

Project Location	Heat Input [1]	CO [2]	NO_X [3]	$PM/PM_{10}/PM_{2.5}$ [4]
ADM – Corn Processing, IA	293	0.072 (30 Day) GCP	0.0200 (30 day) (ULNB, FGR)	0.005 (FNG)
Appleton Coated, WI	285	0.120 (GCP)	0.0900 (LNB, FGR)	0.0080 (FNG/LOU)
Conoco Phillips Company – Trainer Refinery, PA	~348	0.019 (Ox-Cat)	0.0076 (ULNB, FGR, **SCR**)	0.0088 (FNG)
BASF -Ethylene/Propylene Cracker, TX	425	0.070 (GCP)	0.0200 (LNB, SCR)	0.0149
British Petroleum - Cherry Point Refinery, WA	363	0.050 (24 hour) (GCP)	0.0280 (ULNB, FGR)	N/A
Arizona Clean Fuels Yuma Llc, AZ	419	0.016 (3 hour) (GCP)	0.0125 (3 hour) (LNB, FGR)	N/A
The Dow Chemical Company –Freeport, TX	410	0.068 (GCP)	0.0186 (LNB, **SCR**)	0.0160 (FNG)
Cargill, Inc. - Blair Plant, NE	277	0.140 (GCP)	0.0500 (30 day) (LNB, FGR)	N/A
Columbia Energy Center, SC	550	0.060 (GCP)	0.0400 (LNB, FGR)	0.0050 (FNG)
Weyerhaeuser Company, AL	300	0.100 (GCP)	0.0500 (LNB)	N/A
Huntsman Polymers Corp. - Odessa Petrochemical, TX	370	0.065 (GCP)	0.0500 (DLNC)	0.0070 (FNG)
NSPS Subpart Da, fossil fuel ≥ 250 MMBtu/hr	Boiler D has limits for: PM; SO_2; VE; and NO_X or NO_X + CO.			
NESHAP Subpart DDDDD [5] ≥ 10 MMBtu/hr	If Boiler 5 is a Gas 1 unit: Work practice Standards Only If Boiler D is a LFF unit limits for: HCl; Hg; CO; and Filterable PM or TSM.			
NESHAP Subpart JJJJJJ	Boiler D is not subject to this NESHAP			

1. Heat input in MMBtu/hr.
2. Primary CO control methods: GCP = good combustion practices; Ox-Cat = oxidation catalyst; and OF = over-fired air.
3. Primary NO_X control methods: ULNB = Ultra Low NO_X Burners; LNB = Low NO_X Burners; FGR = Flue Gas Recirculation; SCR = Selective Catalytic Reduction; OFA = Over Fired Air; and DLNC = Dry Low NO_X Combustors.
4. Primary $PM/PM_{10}/PM_{2.5}$ control methods: NL = No emission limit; FNG = firing natural gas; LOU = Limited Oil Use.
5. Final (January 31, 2013) NESHAP Subpart DDDDD rule. LFF = Light Liquid Fuel, e.g., No 2 fuel oil,

4.2. Nitrogen Oxides (NO_X) BACT Determination

4.2.1. NO_X Formation

The natural gas fired Cogeneration Boiler D s expected to emit 140.74 TPY of NO_X. The EPA's RACT/BACT/LAER Clearinghouse over the last 10 years has a range of NO_X BACT determinations from 0.0076 to 0.09 lb/MMBtu.

NO_X forms in a boiler as a result of the dissociation of molecules in the combustion air or fuel that contain nitrogen (N_2) or oxygen (O_2) atoms. The subsequent recombination of those atoms leads to the formations of at least seven different oxides of nitrogen, i.e., NO_X. There are three types of NO_X that form during combustion. Each of these types is briefly discussed below.

4.2.1.1. *Thermal NO_X*

Thermal NO_X forms at high temperatures of the order of 2,600 ºF or more when N_2 and O_2 dissociate and recombine to form NO_X.

Equation 1. The prominent mechanism is described by the following "Zeldovich" reactions:

$$N_2 + O \rightarrow NO + N \quad \text{and} \quad N + O_2 \rightarrow NO + O$$

Thermal NO_X forms in the high temperature area of the zone. It increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation.

4.2.1.2. *Prompt NO_X*

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

4.2.1.3. *Fuel NO_X*

Fuel NO_X is formed when fuels containing bound nitrogen or reduced nitrogen compounds (such as NH_3 and HCN) are burned. This phenomenon is not important when a unit fires natural gas.

4.2.2. NO_X Control Strategies

Below are brief discussions of the major NO_X control strategies broken down by type: (1) reducing residence time at peak temperature in the furnace; (2) reducing peak temperature in the furnace; and (3) the chemical reduction of NO_X with the inject of ammonia (NH_3) or urea (CH_4N_2O) either in the furnace or a post combustion control device.

4.2.2.1. *Reducing Residence Time at Peak Temperature*

- *Air Staging of Combustion* – In this system, combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that produces a reducing flame. The second stream is injected downstream of the flame and creates an oxygen-rich zone. An Over Fired Air (OFA) system is a type of an air staging combustion system. According to the applicant, Cogeneration Boiler D will utilize an OFA system (see **subsection 4.2.2.2** below).
- *Fuel Staging of Combustion* – In this system, combustion is staged using fuel instead of air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel to air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be slightly oxidizing. Excess fuel in the primary combustion zone dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NO_X to nitrogen.
- *Inject Steam* – Injection of steam causes the stoichiometry of the mixture to be changed and dilutes calories generated by combustion. These actions cause combustion temperatures to be lower, and in turn reduce the amount of thermal NO_X formed. Steam injection is normally applied to gas turbines and not to boilers, as injecting water into the boiler would reduce the boiler thermal efficiency.

4.2.2.2. *Reducing Peak Temperature*

- *Flue Gas Recirculation (FGR)* – This technology involves recirculation of cooled flue gas back to the boiler, which reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal NO_X concentration that is generated. FGR is normally used to quench the flame, reducing both temperature and oxygen levels, thereby reducing the uncontrolled NO_X emissions.
- *Natural Gas Reburning (NGR)* – The natural gas reburning process involves the introduction of natural gas into the burning zones of the boiler. The first zone is the primary combustion area where 80 to 85% of the fuel is burned. In this area, fuel is fired typically using the existing burner systems, which also can be low-NO_X burners. In the second zone, downstream of the primary combustion zone, the remaining fuel is introduced to form a slightly fuel rich combustion zone. This area is often referred to as the reburn zone, where hydrocarbon compounds are formed that react with NO_2, the primary form of NO_X in combustion processes. The reactions of these hydrocarbon radicals and nitrogen oxide ultimately form nitrogen, which therefore inhibits the NO_X formation process, i.e., Zeldovich reaction. The third zone, downstream of the

reburn zone, is often referred to as the burnout zone where combustion air is added to combust the remaining hydrocarbon compounds.

The overall combustion process is typically fuel lean. This technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system to provide less excess air (LEA). Reburn has been demonstrated using natural gas, coal, residual oil, and Orimulsion®. Reductions in NO_X from 40 to 70% have been demonstrated with this wide variety of fuels.

- *Over-Fire Air (OFA)* – When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the combustion temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA zone. The new natural gas-fired Boiler D will utilize an OFA system to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. The OFA system injects hot air at high velocities into the furnace.
- *Burners out of Service (BOOS)* – An alternative to dedicated OFA ports is BOOS. BOOS is implemented by taking one burner or row of burners out of service. Out of service burner/burner rows act as OFA ports by permitting the other burners to run lean. The remaining required combustion air is through the BOOS to complete combustion. BOOS reduce boiler efficiency by increasing the excess O_2 requirement by about 1%.
- *Separated Over Fired Air (SOFA)* – SOFA is similar to OFA with the exception that the OFA stream is separated from the burner combustion air prior to the introduction of FGR. OFA is then directed to the OFA ports without any combustion air and all of the FGR is directed to the burners. Providing OFA with out FGR assist with burnout of CO at the OFA level, thereby decreasing CO and overall NO_X emissions. Segregating the OFA increases the percentage of FGR through the burner without increasing the total mass flow of FGR. The technique maximizes the benefits of FGR and OFA.
- *Less Excess Air (LEA)* – The amount of excess air in the combustion zone has been correlated to the amount of NO_X generated. Limiting excess air to the boiler can limit the NO_X content of the flue gas.
- *Combustion Optimization* – Combustion optimization refers to the active control of combustion by measuring boiler oxygen level, combustion zone temperature, etc., and adjusting boiler operating parameters in response. The active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. The new natural gas-fired Boiler D will be optimized for maximum combustion efficiency, and boiler operating parameters will be continuously monitored.
- *Low NO_X Burners (LNB)* – A LNB provides a stable flame that has several different burning zones. For example, the first zone can be primary combustion; the second zone can be Fuel Reburning (FR) with fuel added to chemically reduce NO_X; and the third zone can be the final combustion in low excess air to limit the temperature. Low-NO_X burners can be employed for natural gas and fuel oil firing. Ultra-low-NO_X burners have been designed in recent years, which achieve very low levels of NO_X emissions (see below). These type burners will be utilized on the new natural gas-fired Boiler D.
- *Ultra-Low NOX Burners (ULNB)* – ULNB differ from LNB in several ways:
  - Are longer and have a larger diameter throat;
  - Require approximately 30% more FGR; and
  - Require a high pressure drop (10 to 12 w.c, typical burners are 5 to 6 w.c.).

  According to the applicant BACT determination, ULNB have a NO_X reduction control efficiency of 85%.

4.2.2.3. *Chemical Reduction of NO_X*

- *Selective Non-Catalytic Reduction (SNCR)* – In a SNCR system, NH_3 or CH_4N_2O is injected in the furnace at a point in the process characterized by a suitable temperature window between about 1,500 and 1,900 °F depending on residence time, turbulence, oxygen content, and a number of other factors specific to the given

gas stream. The reaction products are N_2 and water vapor (H_2O). SNCR destroys NO_X by a multi-step process which is simplified in the equations below.

Equation 2. NH_3 reacts with available hydroxyl radicals (OH*) to form amine radicals (NH_2*) and water per the following theoretical equation:

$$NH_3 + OH^* \rightarrow NH_2^* + H_2O$$

Equation 3. Amine radicals combine with NO to form nitrogen and water as follows:

$$NH_2^* + NO \rightarrow N_2 + H_2O$$

Equation 4. The two steps are typically expressed as a single "global reaction".

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

Similar simplified reactions describe the destruction of NO_2.

One drawback with SNCR is that some of the NH_3 can be converted to NO_X and excessive NH_3 injection is occasionally required to effect good reduction. Excess NH_3 (called slip) can combine with chloride and sulfate species in the exhaust and cause increased visible and $PM_{2.5}$ emissions. Additionally good CO control is necessary when employing SNCR due to interference with the reaction as described.

Equation 5. CO competes with NH_3 for available OH radicals needed to affect Eq. 2.

$$CO + OH^* \rightarrow CO_2 + H^*$$

As indicated above, the temperature window for SNCR is very important because, outside of it, either (a) more NH_3 slips through the system or (b) more NO_X is generated than is being chemically reduced. NH_3 slip has the potential to affect boiler operation, cause ammonium bisulfate formation on the downstream boiler components and cause a visible plume from the exhaust stack. A typical SNCR system can achieve NO_X reductions of up to 50 to 60%.

- *Selective Catalytic Reduction (SCR)* – In a SCR system, the same reaction as described above for a SNCR system occurs in the presence of catalyst in a chamber at a lower temperature than encountered in the furnace. The reactions are more complete and efficient and NH_3 slip is minimized. A typical SCR system can achieve NO_X reductions of at least 80%. Also according to recent literature, SCR will also help to destroy VOC.[1] It is also a well-documented strategy for dioxin furan control.[2]

  SCR catalysts consist of two types: base metal oxides and zeolite. In an SCR system, a base metal oxide catalyst (vanadium, titanium or platinum) is embedded into a ceramic matrix structure. The zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. Different catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, NH_3/NO_X ratio, and exhaust gas O_2 concentrations for optimum control.

  A common disadvantage for all catalyst systems is the limited temperature window where the NO_X reduction process takes place. The reaction occurs typically between about 320 and 400 °C (600 to 800 °F). However, catalyst are available that allow reactions at higher and lower temperatures. For example, platinum catalysts allows this temperature window to be lowered to about 550 °F, while special low temperature catalysts have been developed to operate as low as 300 °F. These temperatures occur after the economizer of the boiler. Operating outside this temperature range results in failure to remove NO_X and/or harm to the catalyst system. Chemical poisoning can occur at lower temperature conditions, while thermal degradation can occur at higher temperatures. Additional NO_X emissions can be produced at higher temperatures. Reactivity can only be restored through catalyst replacement. Sufficient O_2 is required to

[1] E.g. Leibacher, U., Bellin, C., and Linero, A. High Dust SCR Solutions. International Cement Review. December 2006.

[2] E.g. Tzimas, E., and Peteves, S.D. NO_X and Dioxin Emissions from Waste Incineration Plants. Joint Research Center, European Commission. Circa 2001.

ensure successful reactions. For most SCR applications that have been effective, O_2 concentrations have been in excess of 2% in the flue gas. The SCR catalyst typically has a finite life. Some NH_3 typically slips through the catalyst without being reacted.

There are two types of SCR systems that potentially could be applied to the proposed natural gas-fired Boiler D: conventional SCR and "tail-end" SCR. In a conventional SCR system, the catalyst is located just downstream of the boiler economizer. This location is necessary to operate in the appropriate temperature window for SCR (550 to 800 °F). The proposed fuels (natural gas and No. 2 fuel oil during emergencies) do not present a significant possibility of catalyst poisoning; therefore, this configuration could be possible in the new natural gas-fired boiler.

The other possible configuration is a "tail-end" configuration. This type of installation allows the SCR to be placed downstream of all other pollution controls (particularly PM controls), minimizing the chance of severe catalyst degradation or fouling due to the ash constituents. This configuration would also be possible in the new natural gas-fired boiler, but is not necessary since there are no PM controls required due to the clean nature of natural gas.

4.2.3. Applicant's Proposal for NO_X.

The applicant's BACT proposal is 0.06 lb/MMBtu on a 30-day rolling basis using ULNB and OFA and is included in the top row of **TABLE 6**. It should be noted that the applicant proposed this NO_X emission limit when it intended on using fuel oil in the boiler for up to 15% of the time in any given year and up to 10% of the time in any three year period. However, this fuel oil firing proposal was withdrawn by the applicant when its ramifications with regard to NSPS Subpart DDDD and the Gas 1 subcategory came to light. Solely firing natural gas in the boiler should in of itself allow for lower NO_X emissions.

According to the applicant the most effective NO_X control strategies are:

"SCR and ultra-low-NO_X burners are highly effective in controlling NO_X emissions and will achieve the maximum degree of NO_X emission reduction…….SCR has an estimated NO_X removal efficiency of 90 percent, ultra-low-NO_X burners have an estimated NO_X removal efficiency of 85 percent, and low NO_X burners with FGR (reducing residence time at peak temperatures) have an estimated NO_X removal efficiency of 50 to 60 percent. Reducing peak temperatures provides an efficiency of 15 to 25 percent. FGR systems employ a combination of these methods to achieve NO_X reduction. Other technologies have not demonstrated equivalent levels of control for NO_X."

With regard to the cost effectiveness of NO_X control strategies the applicant states:

"The identification, technical evaluation, and ranking of the available control technologies indicate that ultra-low-NO_X burners coupled with SCR provides the maximum degree of NO_X emission reduction. The evaluation of the energy, environmental, and economic impacts demonstrates that incremental cost of SCR is extremely costly. At approximately $2.9 to 3.9 million in capital costs and $745,000 in annual costs, the SCR system would be expensive. If NO_X emissions can be limited to 0.03 lb/MMBtu or less with ultra low-NO_X burners, the cost effectiveness is well over $10,000 per ton of NO_X reduced."

"The next most effective NO_X control technology, ultra-low NO_X burners, along with advanced combustion design and controls, is selected as BACT for Boiler D. Based on the previous BACT determinations for this technology, a NO_X emission rate of between 0.0125 and 0.09 lb/MMBtu is achievable. Since the new boiler manufacturer has not yet been selected, a NO_X emission rate of 0.06 lb/MMBtu, 30-day rolling average, is proposed as BACT for Boiler D. A lower NO_X emission rate may be determined to be achievable after selecting a boiler manufacturer."

"The NSPS Subpart Da contains NOx emission standards for fossil fuel firing. The applicable standards for natural gas or fuel oil firing, for units for which construction commenced after May 11, 2011, are as follows:

- *NO_X – emissions limited to 0.70 lb/MW-hr gross energy output, or 0.76 lb/MW-hr net energy output, based on a 30-day rolling average; and*

- *NO_X + CO – as an alternative to meeting the NO_X standard above, the owner/operator may elect to meet a combined limit for NO_X plus CO emissions of 1.1 lb/MW-hr gross energy output, or 1.2 lb/MW-hr net energy output, based on a 30-day rolling average.*

The proposed NO_X BACT limit will comply with the Subpart Da emission standards. The proposed limit of 0.06 lb/MMBtu is equivalent to approximately 0.40 lb/MW-hr gross energy output."

4.2.4. Departments Review

The Department recognizes that emissions from the Cogeneration Boiler D will be relatively low due it's firing of clean natural gas. The low emissions from the boiler could make the addition of add on pollution controls cost prohibitive when compared to the mass of pollutants removed, specifically NO_X and CO. NO_X controls are discussed below.

The applicant proposed use of ULNB and OFA for the boiler to control the emissions of NO_X. With regard to the use of a SNCR system to control NO_X emissions the applicant states:

"SNCR has been demonstrated as a feasible technology and can achieve NO_X reductions of up to 50 to 60 percent. However, SNCR is not feasible on a natural gas-fired boiler, because temperatures are too high in the furnace (>2,000 °F), and there is not sufficient residence time in the proper temperature window downstream of the boiler."

The applicant also indicates that the EPA's RACT/BACT/LAER Clearinghouse (RBLC) does not support the use of SNCR as BACT for NO_X control for natural gas fired boilers. Literature supporting this assertion is available. In particular, a SNCR system can be effective in reducing NO_X emission from a boiler firing natural gas, but has not been showed to be effective in reducing NO_X to below approximately 0.05 lb/MMBtu[3]. However, this paper indicates that SNCR is worth considering if a unit has already installed or is planning to install a SNCR system for control of NO_X emissions while firing oil or coal. This paper also provides the control efficiencies and annual cost per ton of NO_X removed for various NO_X control strategies for natural gas fired boilers. These efficiencies and cost are summarized in Table 7 below (note SNCR is not list as a control strategy).

TABLE 7 – COMPARISION OF NO_X CONTROL STRATEGIES.

Control Strategy	NO_X Reduction% [1]	Annualized $/Ton NO_X Removed
FGR/LNB	25-75	900
OFA/BOOS	25	400-600
SOFA & FGR	50-80	1,300-1,500
LNB	25	70-100
LEA/OFA	0-20	30-50
ULNB	up to 90	6,000-8000
SCR	90	6000-8000
Water Injection	25-35	400-600

1. Decrease in NO_X emission (%) compared to conventional gas burners.

The Department agrees that SNCR systems are not effective for NO_X control for new natural gas fired boilers. Further, the Department believes that ULNB can achieve NO_X reductions in the 80% to 90% range when firing natural gas making the selection of a SCR system unnecessary for Cogeneration Boiler D at the Okeelanta Cogeneration Plant. The possible additional NO_X reduction that would be provided by a SCR system would be approximately 15 TPY which would not provide a significant environmental benefit nor would it be cost effective. The Department believing a SCR system would not be cost effective does not mean it accepts the cost effectiveness of $11,758/tons of NO_X removed at a 90% control efficiency provided by the applicant for a SCR

[3] N. S. Schindler, and A. Adriani, *Practical Considerations for Converting Boilers to burn Natural Gas*, Combustion Components Associates, Inc., 2012 PEERS Conference (**P**ulping, **E**ngineering, **E**nvironmental, **R**ecycling, & **S**ustainability), October 14-18 2012.

system. Instead, the Department believes that the approximate 10% increase in NO_X removal efficiency that a SCR system may provide when compared to ULNB technology is not worth the additional cost.

This conclusion is further supported by literature from RJM international which indicates 80% reduction utilizing their ULNB when firing natural gas.[4] Figure 6 below shows ULNB prior to their installation in a 640 MW natural gas and biomass fired boiler in the Netherlands. Figure 7 below show the latest RJN International ULNB.

Figure 6. ULNB Prior Installation in Boiler in the NE. **Figure 7. Latest RJM International ULNB.**

With the ability of ULNB to provide up to a 90% reduction in NO_X emissions from a natural gas fired boiler, the applicant's request for an emission rate of 0.06 lb/MMBtu appears to the Department to be high. Based on the EPA's AP-42 emission factors (Chapter 1.4, Table 1.4.1, link to Chapter 1.4) a post-NSPS natural gas fired boiler would have an uncontrolled NO_X emission rate of approximately 0.186 lb/MMBtu. Using the NO_X control efficiency assumed by the applicant for ULNB of 85% (page 33, subsection 5.3.3 of the application), the controlled emission rate from this post-NSPS natural gas fired boiler would be 0.028 lb/MMBtu. This controlled NO_X emission rate is 53% less that the 0.06 lb/MMBtu rate proposed by the applicant.

The applicant also proposed a 30 day rolling average to show compliance with the 0.06 lb/MMBtu NO_X emissions limit. Such a long averaging time along with a rather high NO_X emissions limit appears unwarranted. This conclusion is supported by EPA RACT/BACT/LAER Clearinghouse (RBLC) survey data for NO_X emissions from natural gas fired boilers that was provided by the applicant which is shown in Table 8 below. The NO_X emissions data in Table 8 is for normal used boilers of greater than 250 MMBtu/hr of heat input.

Table 8 – EPA RACT/BACT/LAER CLEARINGHOUSE (RBLC) NO_X EMISSION DATA.

ID No.	Facility Name	State	Permit No.	Heat Rate	Limit	Basis	Controls
IA-0088	Archer Daniels Midland Corn Processing, Cedar Rapids	IA	57-01-080	293	0.0200	30 Day Avg.	ULNB, FGR, GCP
WI-0244	Appleton Coated – Combined Locks Mill	WI	06-DCF-270	285	0.0900	3 Hour Avg.	LNB, FGR
PA-0253	ConocoPhillips Co. Trainer Refinery	PA	23-00031	~348	0.0076	Unknown	ULNB, FGR, SCR
TX-0511	BASF Fina Petrochemicals Ethylene/Propylene Cracker	TX	PSD-TX-903M1	425	0.0200	3 Hour Avg.	LNB, SCR
LA-0177	Amerada Hess Corp. Sea Robin Gas Processing Plant	LA	PSD-LA-712	363	0.400	1 Hour (Max.)	LNB, FGR
WA-0301	BP – Cherry Point Refinery	WA	PSD-02-04	363	0.0280	Calendar Day	ULNB, FGR
AZ-0046	Arizona Clean Fuels Yuma	AZ	1001205	419	0.0125	3 Hour Avg.	LNB, FGR

[4] Emission Reduction Control Technology for Coal, Oil, Gas and Biomass Fired Plants. Link to Brochure

TX-0479	Dow Chemical Co. Operations Freeport	TX	PSD-TX-986M1 46306	410	0.0186	Hourly	LNB, SCR
NE-0024	Cargill, Inc. – Blair Plant	NE	57902CS6	198	0.0700	30 Day Avg.	LNB, FGR
NE-0024	Cargill, Inc. – Blair Plant	NE	57902CS6	277	0.0500	30 Day Avg.	LNB, FGR
SC-0091	Columbia Energy Center	SC	0460-0024-CE	550	0.0400	3 Hour Avg.	LNB, FGR
AL-0199	Weyerhaeuser Co.	AL	109-0001-X017 X018, X019	300	0.0500	---	LNB
TX-0373	Huntsman Polymers Corp. Odessa Petrochemical Plant	TX	PSD-TX-967	370	0.0500		DLNC, FGR

4.2.5. Department's BACT for NO_X

Based on the discussion in **subsection 4.2.4** above, the Department believes that the applicant's proposed BACT NO_X emission limit of 0.06 lb/MMBtu on a 30-day rolling average basis is too high by up to a factor of two. Consequently, the Department will set a NO_X limit of 0.035 lb/MMBtu on a 30 day rolling average with compliance by NO_X-CEMS. This limit should provide enough flexibility if oil firing becomes necessary during times of natural gas curtailment or if NESHAP Subpart DDDDD is changed to allow more liquid fuel firing during normal operation of the boiler or the applicability of Subpart DDDDD to Boiler D is changed.

4.3. Carbon Monoxide (CO) BACT Determination and Volatile Organic Compound (VOC) Emissions

4.3.1. CO and VOC Formation and Primary Control.

CO and VOC are products of incomplete combustion. The natural gas fired Cogeneration Boiler D s expected to emit 187.65 TPY of CO and 12.65 TPY of VOC. The EPA's RACT/BACT/LAER Clearinghouse on range of NO_X BACT determinations are in the range of 0.024 to 0.10 lb/MMBtu.

Combustion in the Cogeneration Boiler D furnace occurs in substoichiometric conditions. As a result, CO is evolved as well as VOC (including hydrocarbon radicals and other species). The CO, hydrocarbon radicals and reduced nitrogen compounds participate in reactions that assist in primary NO_X control (see discussion above).

Sufficient OFA, temperature and turbulence is necessary to complete the burnout of CO and VOC. Clearly throttling NO_X formation by staging combustion using the OFA ports affects CO and VOC formation in the furnace. Basically, the manner by which the boiler is operated (favoring NO_X over CO/VOC control) is part of an overall source emission strategy that considers the emissions limits and costs of add-on controls. Under the low NO_X strategy (newly designed air system including higher OFA ports) moderate levels of CO (and presumably VOC) persist at greater heights within the furnace compared with the previous combustion strategy.

In summary, the GCP incorporated within the BFB design consists of: intimate contact between the bed material and the fuel and sufficient turbulence, temperature and residence time above the OFA ports to the extent allowed by a low NO_X strategy.

4.3.2. Applicant's Proposal.

The applicant's BACT proposal for CO is 0.8 lb/MMBtu for CO based on GCP. The proposed limit for CO is on a 30-day rolling basis. The proposed VOC limit is 0.0054 lb/MMBtu. According to the applicant:

"The identification, technical evaluation, and ranking of the available control technologies indicate that combustion controls and CO oxidation catalyst provide the maximum degree of CO emission reduction. The evaluation of the energy, environmental, and economic impacts demonstrate that oxidation catalyst is extremely costly. At approximately $1.4 to 1.9 million capital cost and $300,000 to $400,000 annual cost, the cost of the oxidation catalyst system is high. The cost effectiveness is over $2,000 per ton of CO reduced. This cost is unreasonable. In addition, a CO catalyst is not necessary on Boiler D for organic HAPs control, as Boiler D will be a minor source of HAPs without a CO catalyst. For these reasons, oxidation catalyst is rejected as BACT for CO emissions for the new natural gas boiler."

The next most effective CO control technology, advanced OFA system and good combustion practice and controls, is selected as BACT for the proposed boiler. Good combustion design and practices are feasible and

reasonable based on the economic, environmental, and energy impacts. A CO emission rate of 0.08 lb/MMBtu, 30-day rolling average, is proposed as BACT for the new natural gas boiler. This limit is within the range of recent CO BACT limits, which range from 0.024 to 1.00 lb/MMBtu. Three of the four most recent determinations were at 0.12, 0.122 and 0.15 lb/MMBtu. The proposed BACT for the NHPC Boiler D is significantly lower than these most recent determinations."

4.3.3. Department's Review and BACT for CO.

The Department accepts the applicants BACT proposal for CO of 0.080 lb/MMBtu on a 30 day rolling average basis. Compliance shall be demonstrated by a CO-CEMS. The CO BACT emission limit is on the high end of the EPA's RACT/BACT/LAER Clearinghouse range of 0.024 to 0.100 lb/MMBtu. However, by providing a relatively high CO limit the boiler can be tuned to meet the NO_X limit of 0.035 lb/MMBtu set by the Department. This NO_X limit is 42% less than the limit request by the applicant of 0.6 lb/MMBtu. The high CO limit should provide assurance that the NO_X limit can be met. For reference and comparison, the final NESHAP Subpart DDDDD (January 31, 2013) would require compliance with a CO limit of 130 ppm @ 3% O_2 as a surrogate for organic HAP which equates to approximately 0.05 lb/MMBtu when firing natural gas and 0.10 lb/MMBtu when firing oil. So long as the Cogeneration Boiler D is primarily fueled by natural gas there is no applicable CO limit with regard to NESHAP 40 CFR 63, Subpart DDDDD. However, per Subpart DDDDD, the boiler may only combust liquid fuel during periods of gas curtailment, gas supply emergencies or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

4.3.4. Department's VOC Limit

The Department accepts the applicant' proposed VOC limit of 0.0054 lb/MMBtu. Compliance shall be demonstrated by an initial stack test and subsequent stack tests to be performed prior to permit renewal cycles.

4.4. $PM_{10}/PM_{2.5}$ BACT Determination

4.4.1. $PM/PM_{10}/PM_{2.5}$ Formation.

$PM/PM_{10}/PM_{2.5}$ emissions are formed from products of incomplete combustion and from chemical reactions between products of combustion that form alkali and ammoniated chlorides, sulfates, nitrates and other such species. The natural gas fired Cogeneration Boiler D s expected to emit 17.48 TPY of filterable and condensable (see discussion below) $PM/PM_{10}/PM_{2.5}$.

According to Rule 62-210.200, F.A.C. (Definitions), $PM_{2.5}$ emissions shall include condensable $PM_{2.5}$. Condensable $PM_{2.5}$ is defined as gaseous emissions from a source or activity which condense at ambient temperatures to form $PM_{2.5}$. For the purposes of PSD, including determinations of applicability and establishment of limitations to avoid PSD, $PM_{2.5}$ emissions shall include condensable $PM_{2.5}$.

Rule 62-297.401, F.A.C specifies EPA Method 202 – Determination of Condensable Particulate Emissions from Stationary Sources, contained in 40 CFR 51, Appendix M, as the compliance method when a $PM_{2.5}$ limit is required by a Department rule or permit.

Refer to Figure 8. The typical $PM_{2.5}$ sampling train is a hybrid of EPA Methods 201A and 202 (EPA Method 5 may also be used in conjunction with Method 202). The first portion (left hand side) is used to sample the gas stream and, by inertial separation, remove filterable PM larger than 10 µm and then filterable PM between 10 and 2.5 µm in aerodynamic diameter.

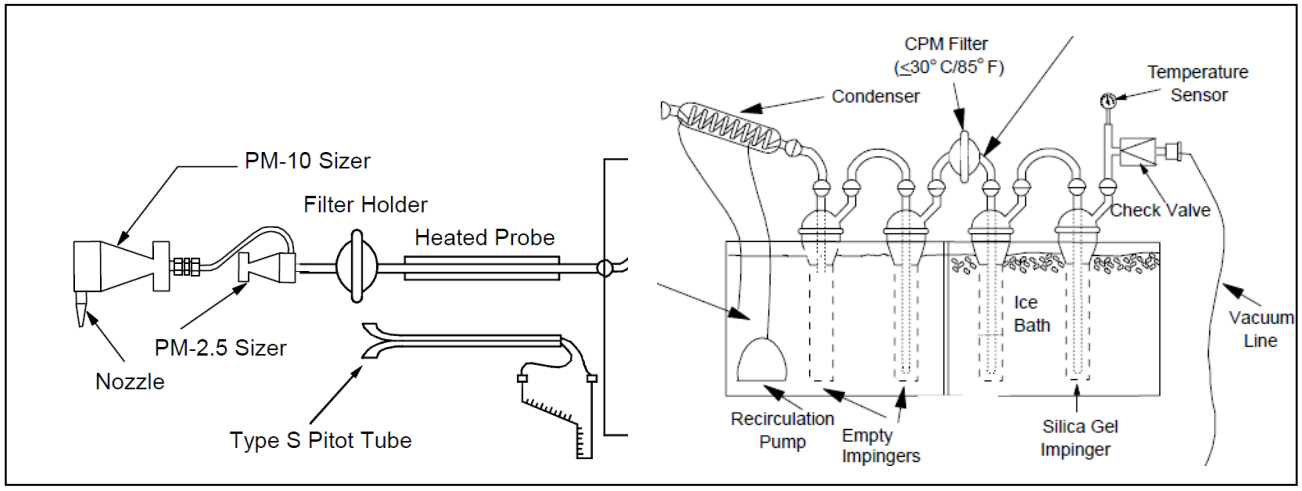

Figure 8. EPA Hybrid Method 201A/202 Filterable and Condensable $PM_{2.5}$ Sampling Train.

A filter is then used to remove by mechanical impaction, interception and diffusion virtually all the filterable $PM_{2.5}$ existing at near-stack temperature conditions. The exhaust gas sample (cleansed of filterable $PM/PM_{10}/PM_{2.5}$) is maintained at a relatively high temperature in a heated probe and then passed through a condenser to nucleate condensable species allowing these gaseous components to condense to condensable PM (CPM) which are then passed through to the CPM filter that is operated at a "defined ambient temperature" ≤ 30°C (85°F).

4.4.2. Applicant's Proposal.

According to the applicant, electrostatic precipitators (ESP), fabric filters, and wet scrubbers are not considered technically feasible as a control alternative for the proposed boiler. Feasible control techniques include burning a clean fuel and GCPs. The applicant states:

"From the review of previous BACT determinations, it is evident that the overwhelming majority of $PM/PM_{10}/PM_{2.5}$ BACT determinations for new natural gas-fired industrial and electric utility boilers have been based on use of clean natural gas fuel and GCPs. BACT determinations have been in the range of 0.0050 to 0.10 lb/MMBtu emissions."

The identification, technical evaluation, and ranking of the available control technologies demonstrates that the proposed control technology for the proposed boiler of primarily firing natural gas and GCPs provides the maximum degree of emission reduction for PM emissions from the proposed boiler. The evaluation of the energy and environmental impacts demonstrate that these controls do not have significant environmental or energy impacts. Based on these technologies, no PM emission limit is proposed for the new Boiler D."

4.4.3. Department's Review and BACT for $PM_{10}/PM_{2.5}$

The Department will not set a filterable plus condensable $PM_{10}/PM_{2.5}$ limit. However, the Department will require an initial stack test utilizing EPA Test Methods 201A and 202 to determine the $PM_{10}/PM_{2.5}$ filterable plus condensable emission rate. The applicant assumed an emission rate of 0.00745 lb/MMBtu. The Department will set BACT for $PM_{10}/PM_{2.5}$ as fuel monitoring verifying that the sulfur content of the natural gas is 2 gr/100 scf or less and for No. 2 fuel oil is less than or equal to 0.05%. Vendor certification can be used in lieu of fuel monitoring. In addition, visible emissions shall not exceed 10% opacity based on a 6-minute average. Meeting this visible emission limit will ensure compliance with NSPS Subpart Da limits of 20% opacity (6-minute average) except up to 27% opacity is allowed for one 6-minute period per hour.

So long as the Cogeneration Boiler D is primarily fueled by natural gas there is no applicable filterable PM limit with regard to NESHAP 40 CFR 63, Subpart DDDDD. As previously stated Boiler D may combust liquid fuel during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year. If the boiler falls into the light liquid fuel category a filterable PM limit of 0.013 lb/MMBtu applies.

4.5. SO_2 Emissions

Meeting the fuel sulfur limits described in **subsection 4.4.3** above will insure compliance with NSPS Subpart Da SO_2 emissions limits of 1.0 pound per megawatt hour (lb/MW-hr) gross energy output or 1.2 lb/MW-hr net energy output.

5. AIR QUALITY IMPACT ANALYSIS

The air dispersion modeling analysis presented in the section was based on Boiler D firing up to 15% No. 2 fuel oil with a sulfur content of 0.05% in any given year with the remaining 85% consisting of natural gas firing. As a result of the requirements of NESHAP Subpart DDDDD, the boiler will only be able to fire fuel oil for 48 hours in any calendar year. Since natural gas is a cleaner fuel than the fuel oil originally proposed for the project, the air dispersion modeling analysis described below is inherently conservative in nature. Consequently air quality impacts resulting from the NHPC Boiler D project will be less than presented in this section. The conservative nature of the air dispersion modeling analysis with regard to the nitrogen dioxide (NO_2) is further strengthen because the BACT NO_X emission rate set by the Department is 42% less than the rate requested by the applicant and used in the modeling analysis described below (0.035 lb/MMBtu versus 0.06 lb/MMBtu).

5.1. Introduction

The proposed project will increase emissions of the following PSD-pollutants at levels in excess of the respective PSD significant emission rates: $PM_{10}/PM_{2.5}$, CO, and NO_X. For these pollutants the applicant must provide a demonstration using approved air quality models that project emissions will not cause or contribute to a violation of an ambient air quality standard (AAQS) or PSD increment for the pollutants where they apply. Of these pollutants, PM_{10}, $PM_{2.5}$, CO, and NO_X (as NO_2) have defined national and state AAQS, and the pollutants PM_{10}, $PM_{2.5}$, and NO_X have defined PSD increments. In addition, significant impact levels (SIL) and de minimis monitoring levels are defined for these pollutants and are used to determine the scope of the modeling analysis and the need for additional ambient air monitoring data. The project site is shown in Figure 9 while Figure 10 shows the site boundary along with the location of all the boilers.

Figure 9. Location of Project Site.

Figure 10. Site Boundary & Boiler D Location.

5.2. Major Stationary Sources Near the Proposed Project

To provide some perspective on the relative scale of the proposed project, the following tables list the largest stationary sources, by pollutant, in and around Palm Beach County. The maximum expected future emissions in TPY from the proposed project are also shown for comparison (the project in highlighted in turquoise). The

"New Hope Power Okeelanta Cogen" facility shown in the tables represents the emissions from the three existing cogeneration boilers (Boilers A, B and C) at the NHPC Okeelanta Cogeneration Plant.

TABLE 9 – LARGEST SOURCES OF NO_X (2011) NEAREST TO THE PROJECT SITE (TPY).

Owner/Company Name	Site Name	County	Emission
US Sugar	Clewiston Facility	Hendry	853
New Hope Power	Okeelanta Cogen	Palm Beach	605
FP&L	West County Energy	Palm Beach	595
Sugar Cane Growers Co-op	Sugar Cane Growers Co-op	Palm Beach	420
Osceola Farms	Osceola Farms	Palm Beach	346
New Hope Power	Okeelanta Cogen (Modification)	Palm Beach	141

TABLE 10 – LARGEST SOURCES OF CO (2011) NEAREST TO THE PROJECT SITE (TPY).

Owner/Company Name	Site Name	County	Emission
US Sugar	Clewiston Facility	Hendry	12,829
Sugar Cane Growers Co-op	Sugar Cane Growers Co-op	Palm Beach	8,718
Osceola Farms	Osceola Farms	Palm Beach	8,540
New Hope Power	Okeelanta Cogen	Palm Beach	1,088
Southern Gardens Citrus	Southern Gardens Citrus	Hardee	382
New Hope Power	Okeelanta Cogen (Modification)	Palm Beach	232
Atlantic Holding	Atlantic Sugar Mill	Palm Beach	172

TABLE 11 – LARGEST SOURCES OF PM/PM_{10} (2011) NEAREST TO THE PROJECT SITE (TPY).

Owner/Company Name	Site Name	County	Emission
FP&L	West County	Palm Beach	496
US Sugar	Clewiston Facility	Hendry	275
Sugar Cane Growers Co-op	Sugar Cane Growers Co-op	Palm Beach	225
New Hope Power	Okeelanta Cogen (Modification)	Palm Beach	231
Osceola Farms	Osceola Farms	Palm Beach	209

To further illustrate the major emission sources nearest to this proposed project, refer to Figure 11 below. All facilities that were used in cumulative modeling for the 1-hour NO_2 NAAQS (see **subsection 5.6.3** below) are shown in Figure 11.

5.3. SO_2 and NO_X Emission Trends from FPL Peninsular Facilities

There are regional efforts underway through the Federal Acid Rain Program and the Clean Air Interstate Rule (CAIR) to reduce emissions of NO_X. Regional NO_X emissions from existing power plants in the Southeast U.S. in 2007 and 2011 are listed in Table 12.

TABLE 12 – NO_X EMISSIONS FROM POWER PLANTS IN THE SOUTHEAST IN 2007 & 2011 (TPY).

State	2007	2011	Δ Since 2007 (%)
Alabama	122,374	61,398	60,976 (50%)
Florida	**184,171**	**54,748**	**129,423 (70%)**
Georgia	107,471	54,823	52,648 (49%)
Kentucky	174,840	92,051	82,789 (47%)
Mississippi	48,546	25,078	23,468 (48%)

State	2007	2011	Δ Since 2007 (%)
North Carolina	59,417	41,348	18,069 (4%)
South Carolina	46,062	23,262	17,229 (30%)
Tennessee	102,886	26,838	76,048 (74%)
Total	**845,767**	**379,546**	**396,690 (45%)**

NO_X emissions from power plants in the Southeast U.S. during 2011 were reduced by nearly 400,000 TPY and 45% referenced to emissions in 2007.

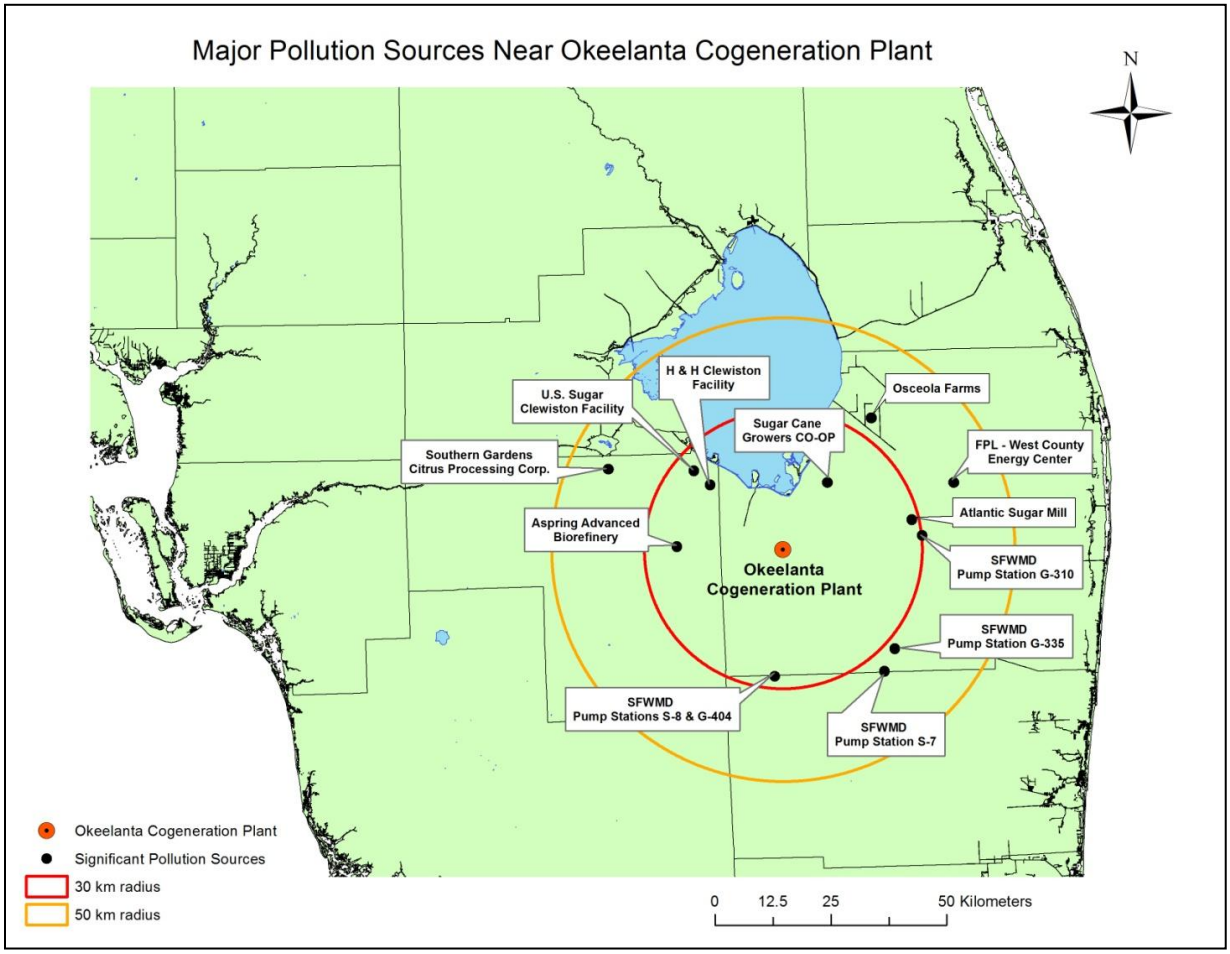

Figure 11. Major Pollution Sources Nearest to the NHPC Okeelanta Cogeneration Plant.

Regional SO_2 emissions from existing power plants in the Southeast U.S. in 2007 and 2011 are listed in Table 13. SO_2 emissions are included because they are a precursor for $PM_{2.5}$. Boiler D triggers PSD for $PM_{2.5}$ emissions.

TABLE 13 – SO_2 EMISSIONS FROM POWER PLANTS IN THE SOUTHEAST IN 2007 & 2011 (TPY).

State	2007	2011	Δ Since 2007 (%)
Alabama	447,189	179,250	267,939 (60%)
Florida	317,582	91,380	226,202 (71%)
Georgia	635,484	186,860	448,624 (71%)
Kentucky	379,837	246,396	133,441 (35%)
Mississippi	69,796	43,211	26,585 (38%)

State	2007	2011	Δ Since 2007 (%)
North Carolina	370,826	73,507	297,319 (80%)
South Carolina	172,726	66,167	106,559 (62%)
Tennessee	237,231	120,325	116,906 (49%)
Total	**2,630,671**	**1,007,096**	**1,623,575 (62%)**

SO_2 emissions from power plants in the Southeast U.S. during 2011 were reduced by more than 1,600,000 tons/year and 62% referenced to emissions in 2007. SO_2 emissions from power plants in Florida during 2011 declined by more than 226,000 TPY and 71%.

The Department graphed gross electrical generation and the SO_2 and NO_X emission trends during the period 1998-2011 from power plants in Florida that report their emissions to the EPA Clean Air Markets database. The results are summarized in Figure 12. By comparison with the overwhelming downtrend of regional and local emissions of SO_2 and NO_X, the emission increases from the Boiler D at the NHPC Okeelanta Cogeneration Plant are very low.

During the period 1998-2011 there was a *decrease* from 818,159 to 82,049 TPY (90%) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* from 335,647 to 57,622 TPY (83%) in NO_X emissions. For comparison purposes, the future project will emit approximately 20 TPY of SO_2 and 141 TPY of NO_X.

The contribution of 20 TPY of SO_2 and 141 TPY of NO_X from the proposed project will not affect the general, overwhelming and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have an appreciable effect on local or regional $PM_{2.5}$ concentrations.

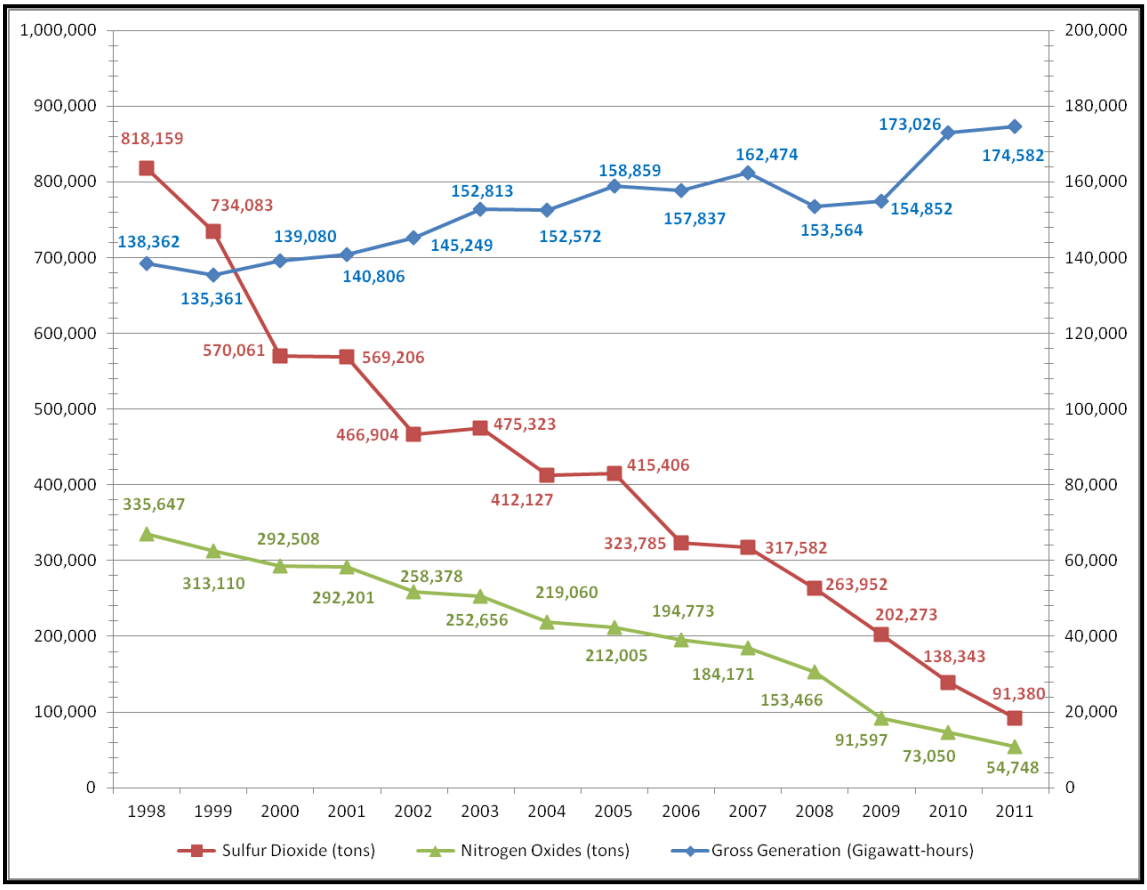

Figure 12. SO_2 and NO_X Emissions from Florida, Acid Rain Units (1998-2011).

5.4. Ambient Air Monitoring Surrounding Proposed Facility

The State ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in counties containing over 90% of the population. As **Figure 13** and Figure 14 indicate, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state.

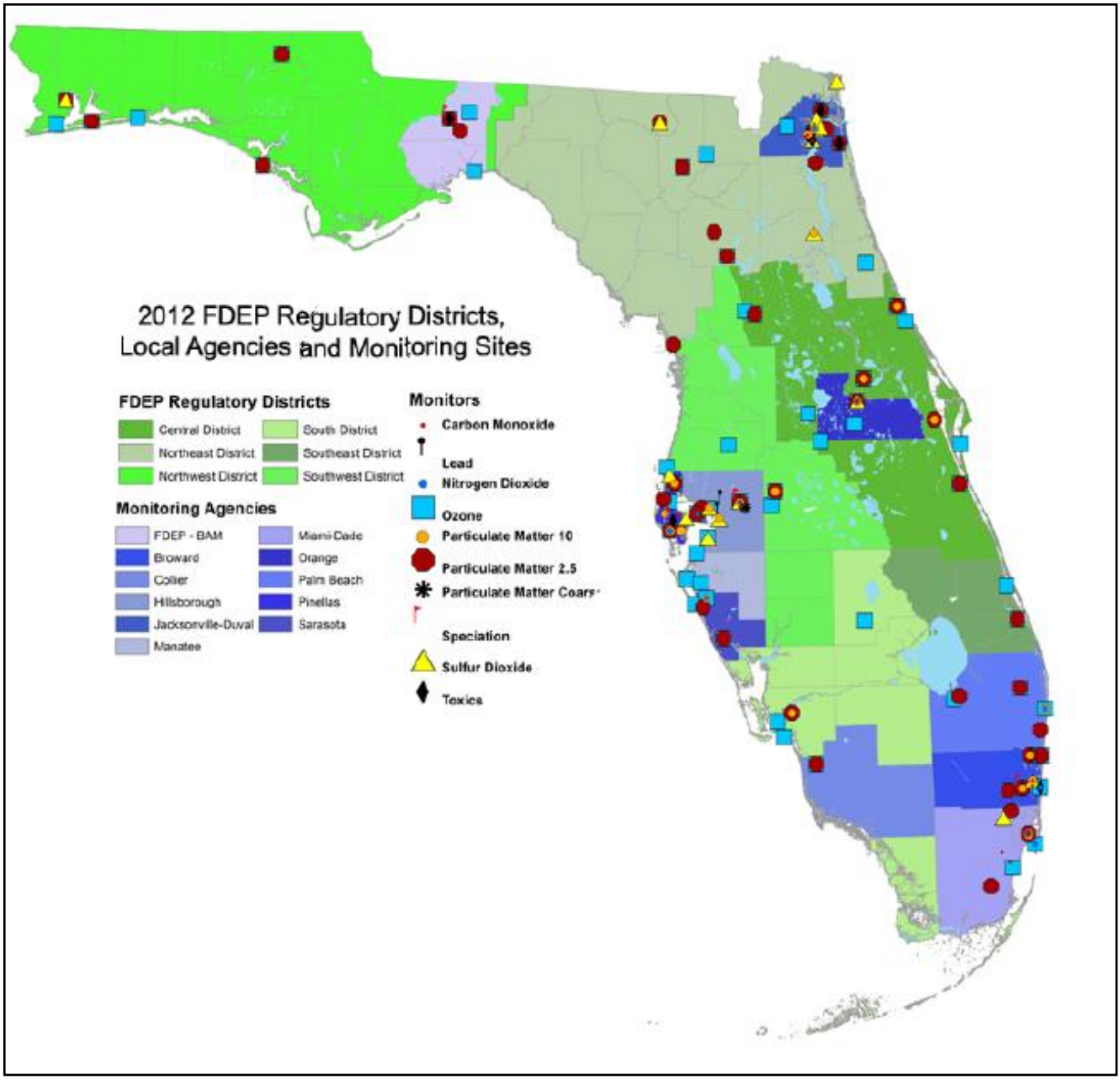

Figure 13. Air Monitoring Network.

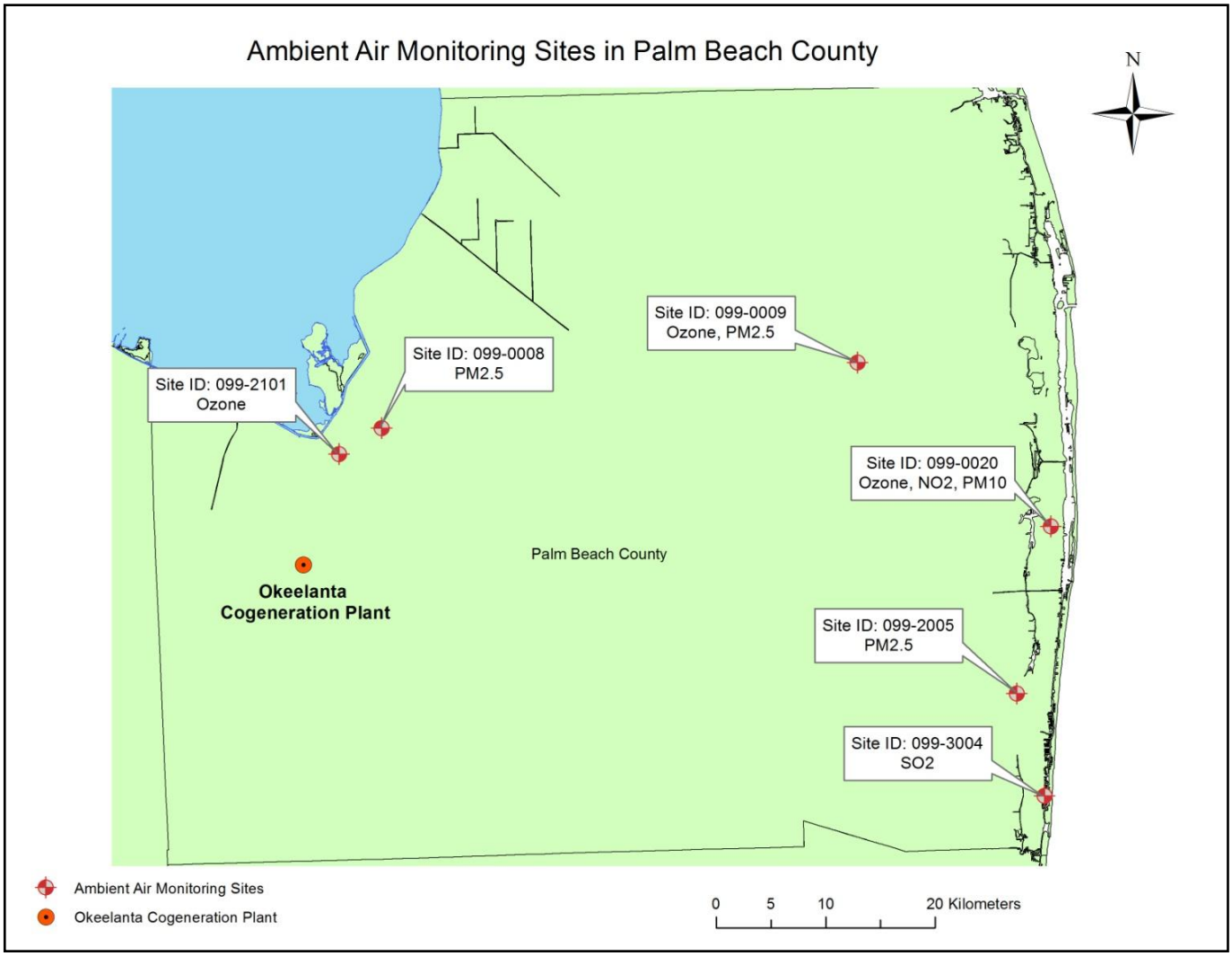

Figure 14. Monitors in Palm Beach County.

These monitors are used to estimate the existing air quality in the area of the proposed facility. The monitors chosen are most representative of the proposed site for due to their close proximity. Table 14 provides the ambient air quality measurements for the selected monitors.

TABLE 14 – AMBIENT AIR QUALITY MEASUREMENTS NEAREST TO THE SITE (2010-2012).

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Palm Beach Co (L0990020)	24-hour [b]	2012	73	150	$\mu g/m^3$
		Annual [c]	2012	22.5	50	$\mu g/m^3$
$PM_{2.5}$	Palm Beach Co (D0990008)	24-hour [d]	2010-2012	19	35	$\mu g/m^3$
		Annual [e]	2010-2012	8.5	15	$\mu g/m^3$
NO_2	Palm Beach Co (L0990020)	Annual [c]	2012	4.2	53	ppb
		1-hour [h]	2010-2012	42	100	ppb
CO	Broward Co (L0110010)	1-hour [f]	2012	2.9	35	ppm
		8-hour [g]	2012	2	9	ppm

Pollutant	Location	Averaging	Ambient Concentration			
Ozone	Palm Beach Co (Z0992101)	8-hour [g]	2012	0.056	0.075	ppm

a. Units are in: micrograms per cubic meter (μg/m^3); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of maximum daily 24-hour concentrations.
e. Three year average of the arithmetic annual means.
f. Not to be exceeded more than once per year.
g. Three year average of the annual 4th highest daily 8-hour maximum.
h. Three-year average of the annual 98th percentile maximum daily 1-hour value
i. Three-year average of the annual 99th percentile maximum daily 1-hour value

The ambient air measurements listed above are values that do not contain 'exceptional events'. An 'exceptional event' is defined by EPA in accordance with 40 CFR 50.14 as an event that affects air quality, is not reasonably controlled or preventable, is an event caused by human activity that is unlikely to recur at a particular location or natural event. Such events include complex wildfires, driven by prolonged drought conditions and other large-scale meteorological patterns. The department has evaluated several $PM_{2.5}$ episodes and found that they occur in conjunction with certain meteorological conditions, combined with very high SO_2 emissions and sulfate deposition.

5.5. Existing Ambient Air Quality Near Project Site – $PM_{2.5}$ and Ozone

Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from authorized agricultural fires, natural drought-related fires and natural emissions from vegetation. These two precursors participate in photochemical reactions that occur on an area-wide basis and are highly dependent on meteorological factors.

Ozone limits and measurements in Table 14 are summarized on three year blocks, rolled annually. The reported ozone value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima were identified for each year and then the average of those three values was reported as the compliance value given in Table 14 and Figure 15.

$PM_{2.5}$ (also known as PM_{fine}) is another key indicator of the overall state of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources as well as fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and ammonia (NH_3) naturally present in the air or added by other industrial sources.

$PM_{2.5}$ limits and measurements are summarized on three-year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 19 micrograms per cubic meter (μg/m^3) as indicated in Table 14 for the Palm Beach County site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2009-2011). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 μg/m^3.

The simple average of all $PM_{2.5}$ measurements within each three years (2009-2011) was also calculated and then the mean of the three averages (8.5 μg/m^3) was reported as the annual compliance value and compared with the standard of 15 μg/m^3. Comparisons of the 24-hour and annual $PM_{2.5}$ compliance values for the Palm Beach County station are shown in Figure 16 along with compliance values for the rest of the state.

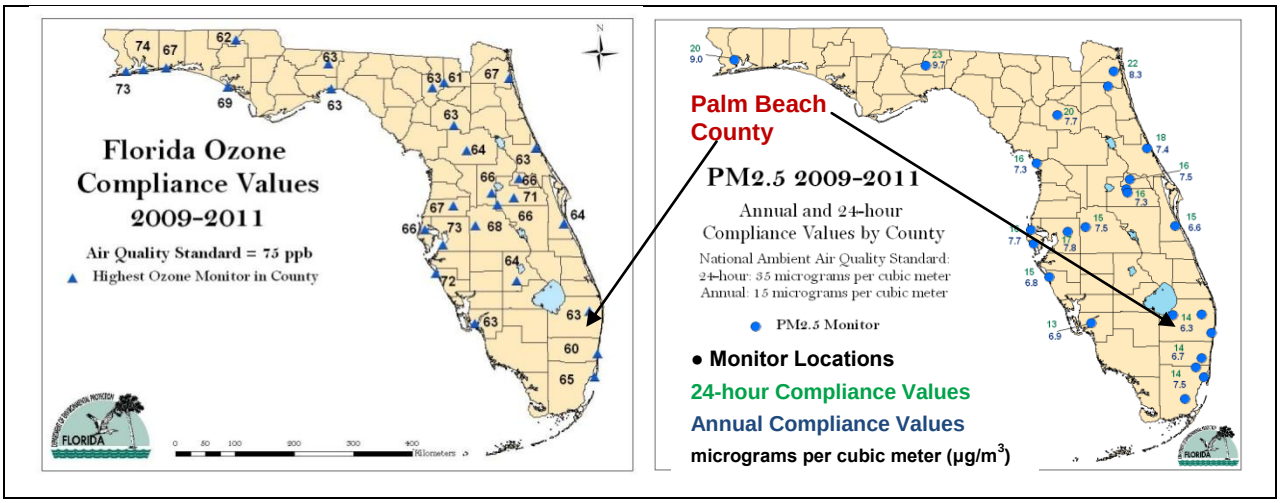

Figure 15. Florida Ozone Compliance Values. **Figure 16. Florida $PM_{2.5}$ Compliance Values.**

The results indicate that Palm Beach County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS.

5.6. Air Quality Impact Analysis

5.6.1. Models, Emissions Data, and Meteorological Data

The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Areas. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered.

Emissions data used in the modeling analysis were obtained from the DEP ARMS database, DEP permit files, and recent PSD permit reviews. The AERMET meteorological data used with the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at the Palm Beach International (PBI) Airport and upper air sounding data collected at the Florida International University (FIU) in Miami. The period of record is 2006 through 2010. The NWS office at PBI is located approximately 66 km (41 miles) east-northeast of the NHPC site and is the closest primary weather station to the study area considered to have meteorological data representative of the Project site. As the PBI meteorological station is only 66 km from the project site and the terrain between the two sites is mostly flat, the wind direction and wind speed frequencies that are experienced at PBI are considered to be very similar to that experienced at the NHPC Site. As such, the PBI wind direction and wind speed frequencies are considered to be representative of the NHPC Site.

5.6.2. Significant Impact Analysis

The general modeling approach for the significant impact analysis for NHPC followed the EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA SIL. For the proposed project, emission increases above the PSD significant emission rates occur for the following criteria pollutants: PM_{10}, $PM_{2.5}$, CO, and NO_X. A significant impact analysis is performed on each of these pollutants to determine if a project can

cause an increase in ground level concentration greater than the SIL for each pollutant. As AAQS and PSD increments exist for NO_2, PM_{10}, $PM_{2.5}$, and CO, a significant impact analysis is required for these pollutants.

In order to conduct a significant impact analysis, the applicant has used the proposed project's maximum short-term emissions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class I and II Areas.

If this modeling for a particular pollutant shows ground-level increases less than its SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments for those pollutants.

For the Class II analysis, a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. Receptor locations used in the modeling analysis were based on Universal Transverse Mercator (UTM) coordinates from Zone 17, North American Datum 198327 (NAD83). The air modeling origin was assumed to be located at the approximate center of the NHPC site, UTM east and north coordinates of 525,200 and 2,939,500 meters, respectively. Receptors were located at the following intervals and distances:

- Every 50 m along the NHPC/Okeelanta property boundary;
- Every 100 m from the plant property boundary to 2,000 m from the origin;
- Every 250 m from 2,000 to 5,000 m from the origin; and
- Every 500 m from 5,000 to 7,000 m from the origin.

Additionally, for each pollutant emitted in excess of the EPA significant emission rate, analyses are required to determine the project's maximum impacts on the air quality-related value (AQRV) at PSD Class I areas. For the Everglades National Park (ENP) PSD Class I area, the AQRV of interest are visibility impairment and sulfur and nitrogen deposition. The ENP is the closest Class I area to the Site and is located approximately 91 km southwest of the NHPC Site. For PSD Class I areas that are located within 50 km of a proposed project site, visibility impairment is in the form of plume blight. For PSD Class I areas that are located beyond 50 km from a proposed project site, visibility impairment is in the form of regional haze. Visibility impairment is determined for a 24-hour averaging time. Total nitrogen and total sulfur deposition are predicted for an annual averaging time.

An initial screening criterion that could exempt a source from AQRV impact review based on its maximum annual emissions and distance from a Class I area has been provided by the Federal Land Managers' (FLMs') AQRV Workgroup (FLAG): Phase I Report-Revised 2010 document. According to the FLAG report, a project that is located more than 50 km from a Class I area will likely not be required to conduct AQRV impacts if the total emissions increase of SO_2, NO_X, PM_{10} and SAM annual emissions (Q, in TPY, based on 24-hour maximum allowable emissions), divided by the distance from the Class I area (D, in km), Q/D, is 10 or less.

Based on the maximum 24-hour emissions for SO_2, NO_X, PM_{10} and SAM, the Q for proposed Boiler D is 408.17 TPY, resulting in a Q/D of 4.49 at the ENP. As this ratio is well below the screening criterion of 10, the proposed project is considered to not likely pose a significant impact on AQRVs at the ENP, pursuant to FLMs' guidance from the 2010 FLAG Report.

5.6.2.1. *Class II SIL*

The maximum pollutant concentrations predicted for the proposed Boiler D project are compared to the PSD Class II SIL in Table 15. The modeling results demonstrate that maximum concentrations due to the proposed project are predicted to be less than the SIL for all pollutants except for the 1-hour NO_2 impacts. As a result, additional modeling analyses for this pollutant were required.

TABLE 15 – MAXIMUM PREDICTED AIR QUALITY IMPACTS COMPARED TO TE PSD CLASS II SIL.

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Ambient Air Standards($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual 24-Hour	0.01 0.4	1 5	50 150	No No
$PM_{2.5}$	Annual 24-Hour	0.01 0.2	0.3 1.2	15 35	No No
NO_2 [a]	Annual 1-Hour	0.06 15.3	1 7.6	100 189	No **Yes**
CO	1-hour 8-hour	36.0 10.8	2,000 500	40,000 10,000	No No

a. Assumes a 75-percent ambient equilibrium ratio of NO_2 to NO_X for the annual averaging time and an 80-percent ambient equilibrium ratio for the 1-hour averaging time ,i.e., the tier 2 modeling approach.

Since the NO_2 impact is greater than the SIL, the air modeling analyses must consider other nearby sources and background concentrations and determine the cumulative impact of these sources for comparison to AAQS and PSD increments.

The 1-hour NO_2 AAQS is a probabilistic standard and compliance is based on the highest predicted 98th percentile (i.e., 8th highest) daily maximum 1-hour average concentrations, on a receptor-by-receptor basis, averaged over 5 years of meteorological data.

The AAQS analysis is a cumulative source analysis that evaluates whether the air quality impact concentrations from all sources will comply with the AAQS. The analysis considers the modeled impacts from existing and future sources at the NHPC Site and, as applicable, emissions from other nearby facility sources, and a non-modeled background concentration that is intended to account for all sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the air quality impact concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at NHPC, plus nearby PSD increment-affecting sources at other facilities. Because a 1-hour PSD Class II increment does not exist for NO_2, an increment analysis is not required for the proposed project.

5.6.2.2. *Class I SIL*

The maximum pollutant concentrations predicted for the proposed Boiler D project are compared to the PSD Class I SILs in Table 16. The modeling results indicate that maximum concentrations due to the proposed project are predicted to be less than the Class I SILs for all pollutants. As a result, detailed analyses to demonstrate compliance with the allowable PSD Class I increments is not required.

TABLE 16 – MAXIMUM AIR QUALITY IMPACTS OF NHPC BOILER D FOR CLASS I SIL.

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$) ENP	Class I SIL ($\mu g/m^3$)	Significant Impact?
$PM_{2.5}$	Annual 24-hour	0.0005 0.015	0.06 0.07	No No
NO_2 [a]	Annual	0.0028	0.1	No

Pollutant	Averaging Time	Max. Predicted Impact (μg/m^3) ENP	Class I SIL (μg/m^3)	Significant Impact?
PM_{10}	Annual 24-Hour	0.0005 0.025	0.2 0.3	No No
a. Assumes 75% conversion of NO_X to NO_2, i.e., the tier 2 modeling approach.				

5.6.3. 1-Hour NO_2 AAQS Analyses

For addressing the 1-hour NO_2 AAQS, EPA has provided guidance (Fox, March 1, 2011) that suggests that the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 km of a project location in most cases. As stated by EPA, the routine inclusion of all sources within 50 km of a project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases for 1-hour NO_2 AAQS compliance demonstrations.

Data on current NO_2 background sources were obtained from FDEP and all facilities located within 30 km of the proposed project. The proposed project's maximum significant impact distance is 5.0 km, based on the worst case 75-percent operating load. Within this distance, termed as the modeling area, the only emission sources are NHPC existing cogeneration Boilers A, B, and C, which are located approximately 60 meters southwest of proposed Boiler D. Boilers A, B, and C are rated at 760 MMBtu/hr while the permitted NO_X emission limit for each boiler is 0.15 lb/MMBtu, based on a 30-day rolling average. A worst-case 1-hour emission rate for the existing boilers, based on review of CEMS data from the boilers, is 0.25 lb/MMBtu (i.e., 190 lb/hr), and was assumed for this analysis.

Beyond the modeling area, the next closest facilities to the proposed project are South Florida Water Management District (SFWMD) Pump Station G-372 and Sugar Cane Growers Co-Op, both located about 17 km away. The emissions for this pump station were not provided but, but based on the other SFWMD pump stations, the NO_X emissions are expected to be between 10 TPY and 26 TPY.

Because the existing Boilers A, B, and C are dominant sources adjacent to proposed Boiler D, the highest predicted 1-hour impacts are expected to be due to the combined impacts of the four NHPC boilers and to occur near the proposed project site. The impacts due to this interaction will mask any secondary maximums that are due to the proposed project's interaction with any other facility that is beyond 10 km from NHPC. For this reason, the existing boilers are the only background sources considered in the modeling analysis.

It is further noted that the non-modeled NO_2 background concentration of 79 μg/m^3 (42 ppb), obtained from the Lantana monitoring station (Site ID L0990020), is considered to conservatively represent the air quality in the vicinity of the NHPC site and more than adequately represents the potential impacts due to emission sources that are not directly included in the modeling analysis.

Table 17 shows the results of this analysis. As shown in the table, emissions from the proposed facility are not expected to cause or contribute to a violation of the 1-hour NO_2 AAQS.

TABLE 17 – AMBIENT AIR QUALITY IMPACTS.

Pollutant	Averaging Time	Major Sources Impact (μg/m^3)	Background Conc. (μg/m^3)	Total Impact (μg/m^3)	Total Impact Greater Than AAQS?	AAQS (μg/m^3)
NO_2	1-hour	63.7	79	142.7	No	188

5.6.4. Ozone Modeling

Projects with VOC and NO_X emissions greater than 100 TPY are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_X emissions from the project to be 13 and 141 TPY respectively.

The ozone monitoring data in Palm Beach County (Site ID 099-2101) is only 7 km north of the proposed project and is sufficient for the purposes of background values at the New Hope Power site.

Ozone site-specific modeling is not typically completed for single source permitting because of its complexity. Ozone is a secondarily formed pollutant that is known to be caused by the regional emissions of VOC and NO_X in combination with meteorological parameters (temperature, rainfall, solar insolation, etc.). Ambient ozone levels in Palm Beach County are primarily due to ozone transport from upwind areas. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Florida has improved over the last 5 years due to improvements in motor vehicle emissions rates. Continued reductions in average motor fleet emissions would be expected to further improve ozone air quality. In addition, implementation of CAIR has resulted in significant actual reductions in existing power plant NO_X emissions throughout Florida. As previously discussed, the NO_X emission reductions across Florida have declined by more than 275,000 TPY over the last 15 years.

To conclusively prove whether or not 141 TPY of NO_X and 13 TPY of VOC will not cause or contribute to a violation, a very sophisticated and expensive model (such as the EPA CMAQ) would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. The effects of the proposed project on ozone would not be measurable considering the overwhelming effects of the statewide reductions and the climatological variability. The uncertainty in any regional ozone model would be greater than the contribution from this project. Palm Beach County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

5.7. Additional Impacts Analysis

5.7.1. Growth-Related Impacts Due to the Proposed Project

According to the applicant, construction of Boiler D will occur over a 24-month period requiring an average of approximately 25 workers during that time with about 5 operational workers after the boiler begins starts up in 2015. It is anticipated that many of these construction personnel will commute to the site. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to construct and operate Boiler D represents a tiny fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

The applicant also states that there are no air quality impacts due to associated commercial and industrial growth given the location of Boiler D. The existing commercial and industrial infrastructure is adequate to provide any support services that Boiler D might require. The addition of the project will have little effect on the increase of growth in the area. The area to the west is expected to remain agricultural, the areas to the south and east contain the Loxahatchee National Wildlife Refuge (NWR), and the areas near the coast have already been designated as areas for potential development.

In conclusion, the existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of Boiler D. The workforce needed to operate the proposed Boiler D represents a tiny fraction of the labor force present in the immediate and surrounding areas.

5.7.2. Impact on Soils and Vegetation,

The primary vegetation, as well as agricultural crop, in the vicinity of the NHPC is sugar cane. The site is surrounded by sugar cane fields for a large distance in all directions. Other agricultural areas are common in the local area, including rice fields, vegetable farming, nurseries, and sod farms. The west edge of the Arthur R. Marshall Loxahatchee NWR is located to the east of the NHPC site; vegetative communities in this area include freshwater tree islands, marsh, shrubs, and cattails. Exotic species have extensively colonized the northern, southeastern, and western portions of the Loxahatchee NWR, most notably melaleuca (Melaleuca

quinquenervia), Brazilian pepper (Schinus terebinthifolius), Old World climbing fern (Lygodium microphyllum), water lettuce (Pistia stratioides), and water hyacinth (Eichhornia crassipes).

Soils in the area are primarily histosols, which are peat soils with high amounts of organic matter. The agricultural lands surrounding the Site are part of the Everglades Agricultural Area, which is noted for its "muck", i.e., rich, black soil that is very fertile. Since the Project's impacts on the local air quality are predicted to be less than the AAQS, impacts on soils and vegetation the site vicinity are expected to be negligible.

5.7.3. Impact on Wildlife

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission sources that experience frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. It is highly unlikely that emissions from NHPC Boiler D will cause adverse effects to wildlife due to the project's low impacts, well below the AAQS. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely.

5.7.4. Class I Area Impacts- Air Quality Related Values (AQRV)

Because the proposed project's Q/D ratio is 4.49 (see **subsection 5.6.2**), the project's emissions are not expected to significantly impact AQRVs of the ENP. As a result, additional analyses to assess visibility impairment and acid deposition at the ENP were not performed. The ENP is the closest Class I area to the Site, located approximately 91 km southwest of the NHPC Site.

6. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the available information, reasonable assurances provided by the applicant, previous determinations for similar projects, and the conditions specified in the Draft Permit. The Department notes that the determinations and conclusions made in this evaluation are specific to this project and do not establish any precedents for the sugar industry, related industries, or electric utility steam generating units in general. These determinations must be made on a case-by-case basis considering each unique set of circumstances. David Read, P.E., is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer by: phone at 850/717-9075; email at david.read@dep.state.fl.us; or mail at the Department's office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.